E-002/CG-88-489RESOLVING DISPUTES REGARDING TERMS OF CONTRACT BETWEEN UTILITY AND QUALIFYING FACILITIES

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Barbara Beerhalter	Chair
Cynthia A. Kitlinski	Commissioner
Norma McKanna	Commissioner
Robert J. O'Keefe	Commissioner
Darrel L. Peterson	Commissioner

In the Matter of the Joint Petition of Dakota County and Winona County for an Order Resolving Disputes Relating to Purchases by Northern States Power Company of Electric Power from the Operation of Solid Waste Recovery Facilities to be Located in Dakota and Winona Counties, Minnesota

ISSUE DATE: July 7, 1989

DOCKET NO. E-002/CG-88-489

ORDER RESOLVING DISPUTES REGARDING TERMS OF CONTRACT BETWEEN UTILITY AND QUALIFYING FACILITIES

PROCEDURAL HISTORY

I. An Overview of this Proceeding

The federal Public Utility Regulatory Policies Act, 16 U.S.C. § 824a-3, encourages cogeneration and small power production, the production of electricity by entities other than public utilities, as a matter of national energy policy. The Act and its implementing regulations, 18 CFR 292.101 - 292.601, establish standards which cogenerators and small power producers must meet for their facilities to be designated "qualifying facilities." Once a facility attains qualifying facility status, a public utility must purchase all the electricity it makes available, generally at full "avoided cost," the amount it would cost the utility to generate the electricity itself. 18 CFR 292.304. Determination of avoided cost, and implementation of the Act generally, is delegated to state regulatory commissions. 16 U.S.C. § 824a-3 (f), 18 CFR 292.401 - 403. Minnesota has implemented the Act by statute and regulation. Minn. Stat. § 216B.164 (1988); Minn. Rules, parts 7835.0100 - 7835.9910.

On July 18, 1988 Dakota and Winona Counties (the Counties) filed a joint petition under Minn. Stat. § 216B.164 (1988) and Minn. Rules, part 7835.4500 asking the Commission to resolve specified disputes between themselves and Northern States Power Company (NSP or the Company) regarding the terms to be included in contracts they were negotiating with the Company. The Company filed an answer, which agreed that the facilities the Counties planned to build would be qualifying facilities and that the disputes regarding contract terms were subject to Commission jurisdiction.

The Commission accepted jurisdiction of the petition under Minn. Stat. § 216B.164 (1988), determined that there were material facts in dispute, and referred the matter to the Office of

Administrative Hearings for contested case proceedings under Minn. Stat. § 14.58 (1988). The Office of Administrative Hearings assigned Administrative Law Judge Richard C. Luis to hear the case.

II. Parties and Appearances

The Department of Public Service (the Department) intervened in the case as of right under Minn. Stat. § 216A.07, subd. 3 (1988) and Minn. Rules, part 1400.6200, subp. 1. There were no other intervenors.

Administrative Law Judge Luis held evidentiary hearings in the matter on December 8, 9, and 12, 1988. Appearances in the matter were as follows: Byron E. Starns and James J. Bertrand, Leonard, Street & Deinard, Suite 2300, 150 South Fifth Street, Minneapolis, Minnesota 55402, appeared on behalf of Dakota and Winona Counties;

Margaret J. Westin, Assistant County Attorney, Dakota Government Center, 1560 West Highway 55, Hastings, Minnesota 55033, appeared on behalf of Dakota County;

Richard J. Johnson, Moss & Barnett, P.A., 4800 Norwest Center, 90 South Seventh Street, Minneapolis, Minnesota 55402, and David A. Lawrence, Attorney at Law, Northern States Power Company, 414 Nicollet Mall, Minneapolis, Minnesota 55401, appeared on behalf of the Company;

Joan C. Peterson and Thomas S. Waldo, Special Assistant Attorneys General, 1100 Bremer Tower, Seventh Place and Minnesota, St. Paul, Minnesota 55101, appeared on behalf of the Department;

W. Stuart Mitchell, Jr. and Susan Mackenzie, Rate Analysts, 780 American Center Building, 150 East Kellogg Boulevard, St. Paul, Minnesota 55101, appeared on behalf of the Commission.

III. Proceedings Before the Commission

The record closed on February 15, 1989. On February 16, 1989 the Administrative Law Judge issued his ORDER ON MOTION TO REOPEN THE RECORD, denying the Counties' motion to reopen the record to admit a newspaper article dealing with the Company's future generation plans. On March 27, 1989 the Administrative Law Judge issued his FINDINGS OF FACT, CONCLUSIONS OF LAW, AND RECOMMENDED ORDER. On May 31, 1989 he issued a Letter-Order clarifying that NSP Exhibits 41 and 42 had been admitted into the record of the proceeding.

The Company and the Counties filed Exceptions to the Administrative Law Judge's report. All parties filed replies to the exceptions. The Commission heard oral argument from the parties on May 31, 1989.

Upon review of the entire record of this proceeding, the Commission makes the following Findings, Conclusions, and Order.

FINDINGS AND CONCLUSIONS

IV. Jurisdiction

The Commission has jurisdiction over this proceeding under Minn. Stat. § 216B.164, subd. 5 (1988) and Minn. Rules, part 7835.4500, which provide as follows:

> In the event of disputes between an electric utility and a qualifying facility, either party may request a determination of the issue by the commission. . . .
>
> Minn. Stat. § 216B.164, subd. 5 (1988).
>
> In case of a dispute between a utility and a qualifying facility or an impasse in the negotiations between them, either party may request the commission to determine the issue. . . .
>
> Minn. Rules, part 7835.4500.

V. Statement of the Issues

The parties have identified the following issues as requiring resolution by the Commission.

1. Timing of Company's Need for Additional Base Load Capacity --When will the Company need additional base load capacity, the point at which avoided costs must be based on the costs of constructing a new base load facility, as opposed to the costs of purchasing third party power or constructing peaking facilities?

2. The Proxy Base Load Plant -- Should the Company's avoided base load capacity costs be based on the costs of Sherco 3, the Company's last-constructed base load facility, or on the costs of the Company's next planned base load facility?

3. Escalation Rate -- What is the proper escalation rate for determining the construction costs of the Company's future generating plants?

4. Equity Adjustment -- Does the proper calculation of the Company's avoided costs require an "equity adjustment" to reflect the higher equity costs which can be expected to result from the debt-like nature of the payments required under the contracts?

5. On-Call Requirement -- How many hours in the year should the contracts require the Counties to provide full committed capacity because of the following contingencies: a. the Company is interrupting or curtailing customers due to extraordinarily high peak load; b. the Company is interrupting or curtailing customers to reduce or avoid the use of oil-fired generation; c. the Company is experiencing a system emergency.

6. Reduction in Accredited Capability -- In the event the Mid-Continent Area Power Pool (MAPP) reduces the Counties' accredited capability, resulting in a reduction of the Counties' committed capacity, should the Counties be required to reimburse the Company for any difference between the cost of replacement power and the cost of power under the contracts?

7. Non-delivery of Committed Capacity -- Should the Counties be required to reimburse the Company for any difference between the cost of replacement power and the cost of power under the contracts if the Counties fail to deliver committed capacity for any reason other than those listed under the force majeure provision of the contracts?

8. Continuing Compliance with MAPP Agreement -- Should the Counties be required to conform their operations to any future amendment(s) to the MAPP Agreement, to which the Company is a signatory?

9. Avoided Societal Costs -- Should the Company's avoided costs be increased by 20% to reflect the conservation and environmental benefits of the solid waste recovery process?

10. Anti-competitive and Discriminatory Practices -- Should the Company face a heightened evidentiary standard because it has engaged in anti-competitive and discriminatory behavior in its dealings with the Counties?

These issues will be addressed by the Commission in the order presented above.

VI. Timing of Company's Need for Additional Base Load Capacity

Until the Company needs new base load capacity, its avoided capacity costs will be based on the costs of new peak load facilities and the costs of purchasing third party power. Since these sources of power are considerably less expensive than constructing a new base load facility, the question of when NSP will need a new base load plant is critical in determining avoided capacity costs. (The contract at issue calls for level monthly payments. The amount of the standard monthly payment will depend upon how much of the contract period uses base load capacity in calculating avoided capacity costs.)

The Company stated that it would require additional base load capacity in 1998. The Counties alleged that the Company will probably need additional base load capacity in 1989, will certainly need it in 1992, and will be in dire straits unless it has acquired more base load capacity by 1996. The Department argued that the most reasonable estimate of when the Company will need additional base load capacity is 1997. The ALJ adopted the Department's position. The Commission agrees with the Department and the ALJ.

The Counties argued that the Company's 1998 date for adding base load capacity was unrealistic in light of the following concerns:

A. The Company's capacity calculations included capacity to which it may not have access: interests in the Clay Boswell 4 and Square Butte facilities, which are the subject of a purchase agreement with Minnesota Power which the Company is seeking to have declared void; the Lower Falls Dam hydroelectric plant, which collapsed and is currently inoperable; and higher capacity from Black Dog Unit 2 than the Company has been able to achieve.

B. The Company's capacity calculations included a capacity purchase from Minnkota Power Cooperative which should not be counted because the purchase was consummated after the Company began negotiating with the Counties.

C. The Company's capacity calculations were allegedly based on a 15% reserve margin, instead of a more appropriate 18-20% reserve margin.

D. The Company based its capacity calculations on the assumption that normal weather patterns would prevail.

Each contention will be examined in turn.

A. The Inclusion of Capacity Whose Availability is Questionable.

The ALJ made factual findings that capacity from the Lower Dam hydroelectric plant and the as yet unachieved capacity from Black Dog Unit 2 had not been included in the Company's projections.

It appears that the Counties may have withdrawn their contention that this capacity was included. Since that is unclear, however, the Commission too finds that those sources of capacity were not counted and do not call into question the Company's projections.

The Company's inclusion of capacity from Boswell 4 and Square Butte raises more serious concerns. The Company alleges that this capacity should be counted because the Company still has a contract with Minnesota Power to acquire it. Since the Company has initiated litigation to void the contract, however, it is difficult to give this claim a great deal of weight. At the least, there is a high level of uncertainty about the Company's access to this capacity.

Even if the Company does not acquire the Boswell 4 and Square Butte capacity, however, its need for base load capacity will only be moved up to 1996. The testimony of the Department and the Company demonstrates that NSP could meet its capacity needs through third party purchases and reliance on peaking facilities until then. In fact, as those parties pointed out, voiding the contract between the Company and Minnesota Power would result in larger amounts of power being available to NSP, as well as other utilities, through MAPP.

This leaves the issue of how to deal with the possibility that the Company will prevail in its litigation and therefore need base load capacity in 1996. Any adjustment to capacity projections made in light of the litigation must reflect a wide range of possible outcomes.

The Company may lose the litigation and acquire the capacity. The Company may prevail in the litigation and not acquire the capacity. The Company may settle the litigation by renegotiating the terms of the sale. The Company may prevail in the litigation and still renegotiate the terms of the sale. Under these circumstances, excluding the capacity entirely appears too extreme. At the same time, including the capacity on the same terms as capacity which is currently owned and operated by the Company appears equally inappropriate.

The Commission agrees with the Department that a middle position is the most reasonable approach, and will set the date that the Company will need new base load capacity at 1997, the mid-point between a date assuming the acquisition of Boswell 4 and Square Butte and a date assuming that the acquisition does not occur.

B. The Inclusion of Capacity Purchased from Minnkota Power Cooperative

The Counties alleged that NSP's purchase of capacity from Minnkota Power Cooperative should not be counted in capacity projections because the purchase was completed while the Company was engaged in serious negotiations with the Counties. In their view, the Company should not have made a purchase affecting avoided costs at that point. The Company, the Department, and the ALJ took an opposing view.

The Commission agrees with the ALJ that the capacity purchased from Minnkota Power should be counted. To prohibit capacity purchases which might affect avoided costs while utilities are negotiating with qualifying facilities would severely limit a utility's ability to secure the most economical power for ratepayers. This is a result directly at odds with the goals of regulation, including the goals underlying the policy of encouraging small power production.

On the other hand, the Commission does not rule out the possibility of refusing to count capacity purchases made in bad faith for purposes of damaging the negotiating position of a qualifying facility. In this case, however, there is no evidence that this occurred. The Company signed a letter of intent, binding it to the Minnkota Power purchase, in 1985, before its negotiations with the Counties were in the final stages. The Company clearly had a duty to conduct the Minnkota negotiations in good faith, and had no duty to attempt to advance the Counties' interests in those negotiations. The Commission finds no basis on this record to reject the inclusion of the Minnkota Power capacity in the Company's capacity projections.

C. The Appropriate Reserve Margin

The Counties alleged that NSP should have used an 18-20% reserve margin in assessing its capacity needs, but used a 15% margin instead. The Company claimed to have used an 18% margin. The Department agreed with the Company, and the ALJ made a finding of fact that 18% was the margin employed. The Commission accepts the ALJ's finding.

The ALJ found that the Counties' contention that the Company was using a 15% reserve margin ignored the Company's plans to construct a peaking plant in 1995. That plant will enable the Company to maintain its 18% reserve margin at a time when increased demand would otherwise allow it to drop. The Commission accepts the ALJ's findings on this issue and finds that the Company's 18% average reserve margin provides adequate protection to NSP's ratepayers.

D. Assumption of Normal Weather Patterns

The Company based its capacity assessment on the assumption that normal weather patterns would prevail throughout the forecast period. The Counties suggested that assuming normal weather conditions in the face of last summer's heat and drought was too conservative. The Department and the Company disagreed, as did the ALJ.

The Commission finds that the Company acted properly in assuming normal weather patterns. Both utilities and regulators routinely adjust demand data to reflect "normalized" weather conditions, among other variables. Such adjustments are essential for any meaningful use of the data collected to aid utilities and regulators in long term planning. The record-breaking heat of last summer does not establish on its face that a permanent change in weather patterns has occurred or that procedures for forecasting weather-related demand factors should be revised. No testimony on these subjects was offered. The Commission declines to find on this record that the Company should be required to assume a continuing upward trend in summer temperatures.

Based upon the factors discussed above, the Commission accepts and adopts the ALJ's finding that the Company will need additional base load capacity in 1997.

VII. The Proxy Base Load Plant

NSP proposed to calculate its avoided base load capacity costs in terms of its next planned base load facility, the "reference plant." The Counties proposed to use the Company's last completed base load facility, Sherco 3, instead. The Department took the Company's position, which was also adopted by the ALJ.

The Counties opposed using reference plant costs to determine avoided costs for two reasons: reference plant costs were viewed as too speculative to provide a reliable basis for determining avoided costs, and all the Company's contracts with qualifying facilities to date had based avoided costs on the costs of Sherco 3.

The Commission believes that the concept of avoided costs, as well as the plain meaning of the term itself, refers to the costs of future generation. Those are the costs which can be avoided, at least in part, by purchasing cogenerated power, and those are the costs upon which avoided costs should normally be based. This is the approach embodied in the Commission's rules regarding qualifying facility rates. Minn. Rules, parts 7835.0300 - 7835.1200; 7835.3600 - 7835.3800. It is also the approach favored by the Federal Energy Regulatory Commission, which recently criticized the method advocated by the Counties:

> In this method, the plant being used to calculate avoided cost already exists and may have been chosen to measure avoided cost because its costs were easily ascertainable, not because it bore resemblance to the actual plant avoided. This can be a problem because the relevant incremental costs to the utility are not the costs associated with the last kilowatt of capacity provided, or the last kilowatt-hour that needs to be generated. If the characteristics of the last plant committed do not resemble those of the next plant to be added (or of power purchases contemplated), then the "committed unit" approach is not appropriate.
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> Federal Energy Regulatory Commission, Notice of Proposed Rulemaking, Administrative Determination of Full Avoided Costs, Sales of Power to Qualifying Facilities, and Interconnection Facilities, Docket No. RM88-000, at 37-38 (March 16, 1988).

The Company's next base load facility will not be a traditional coal-fired plant like Sherco 3, but a fluidized bed coal plant. Since Sherco 3 is not essentially similar to the Company's next base load facility, its costs should not be used as a proxy for the costs of the next facility.

The Commission agrees that the costs of the Company's next base load plant cannot be determined with as much accuracy as the costs of Sherco 3. That does not render those costs speculative, however. Forecasting future generation needs and engaging in the long term planning necessary to meet those needs are integral parts of providing utility service. Electric utilities, including NSP, have a great deal of experience and expertise in long range planning, including designing power plants which rely on developing technology. They are required to submit periodic reports describing their long range planning processes and detailing the conclusions to which those processes have led them. These reports are reviewed by the Commission to ensure prompt detection of any planning deficiencies which could jeopardize adequate, economical service for future ratepayers. Minn. Rules, parts 7825.2800; 7825.2830; 7835.0500-.0600; 4220.2700-.2800. The reference plant comes out of this environment and represents the best information available regarding the Company's future base load generation.

The Counties correctly note that transmission costs associated with the new plant will be uncertain until a final site is selected. The Commission agrees with the ALJ, however, that averaging the transmission costs from all four potential sites will provide a reasonable estimate of actual transmission costs, since there are no gross disparities between any of the distances involved. The Commission does not believe that the uncertainty about the final site for the plant, or the uncertainty regarding fuel sources[1], indicates the kind of pervasive uncertainty which would require abandoning the reference plant as the basis for determining avoided capacity costs.

The fact that all existing contracts with qualifying facilities use the costs of Sherco 3 to determine avoided capacity costs does not mean that these contracts should do so. It was proper to use Sherco 3 to calculate avoided capacity costs when it was the next planned base load facility; it is proper now to use the reference plant, the next planned base load facility, to calculate avoided costs.

VIII. The Escalation Rate

The escalation rate is the annual rate at which construction costs for the Company's future generating facilities can be expected to increase. The higher the escalation rate, the higher the projected costs of new facilities and the avoided costs payable to the Counties. NSP proposed an escalation rate of 2% through 1996 and 4% thereafter. The Counties proposed a level escalation rate of 5.5%. The Department proposed a 3% escalation rate through 1996 and 4% thereafter. The ALJ adopted the position of the Department.

The Commission agrees with the Department and the ALJ that both the Company and the Counties have, in their analyses of this issue, indulged a disproportionate number of assumptions in their favor. The Commission agrees that an escalation rate between the two extremes proposed by those parties is more likely to prove accurate.

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[1]The Counties note that the type of fuel to be used by the new plant is as yet undetermined. Since the Counties and the Company have agreed on energy rates, however, this uncertainty has no effect on the amount payable to the Counties.

A. The Company's Proposal

NSP based its proposed escalation rates on an analysis of general inflationary trends by a five-person team of professional economists. That team projected a general average annual inflation rate through 1996 of 4%. The Company then asked professionals in its Plant Engineering and Construction Department, Financial Operations Department, Energy Supply Planning Department, Production Performance and Services Department, and Fuel Procurement Department to analyze the effect of that inflation rate on NSP plant construction costs generally, and on the costs of the reference plant in particular. These professionals reported, based on past experience in plant construction and detailed knowledge of the reference plant, that the escalation rate for plant construction costs would run 2% below the general inflation rate.

The Commission does not join the Counties in condemning the Company's reliance on in-house experts to determine what the escalation rate for future generating facilities will likely be. The Company employs capable economists, engineers, planners, and other professionals to assist it with the long range planning required by its duty to serve. It is reasonable for the Company to look to these people for purposes of a proceeding like the present one as well. The Commission also agrees that the impact of inflation varies dramatically between different regions of the country, between industries, and even between utility companies. There is value, then, in receiving situation-specific analyses of inflation's likely impact from people who work for the Company and are familiar with the specific construction projects at issue. At the same time, however, it must be borne in mind that these analyses represent the Company viewpoint and are prepared by people bound by a higher duty of loyalty and exercising less independence than consultants and other non-employee expert witnesses.

The Commission believes that the Company's escalation rate projections are overly optimistic. The 4% general inflation rate on which they are based is at one extreme of a reasonable range. Adopting a rate at either extreme should be done with caution, since it increases the probability of wide disparity between the projection and the actual rate. Furthermore, adopting the lowest possible general inflation rate, in the absence of strong evidentiary support, is inconsistent with the Commission's statutory responsibility to implement the act "in accordance with its intent to give the maximum possible encouragement to cogeneration and small power production consistent with the protection of the ratepayers and the public." Minn. Stat. § 216B.164 (1988). Finally, Data Resources, Inc., an objective and widely quoted source on inflation rates, projects an inflation rate of 5% for the same period. The Commission therefore finds that the 4% general inflation rate proposed by the Company is unreasonably low.

The Commission also believes that the Company is overly optimistic in believing it can keep plant construction cost escalation 2% under general inflation rates. While the Commission fully appreciates that plant construction costs are often not subject to the same inflationary pressures as other endeavors, the 2% differential is unacceptably high. From 1983 to 1988, the Handy-Whitman Index, a nationally recognized source of information on the inflation rate for steam-generation power plant construction, has consistently placed that rate only 1% below general inflation.

The Company contends that it can hold its escalation below the norm because of its singular expertise in plant-building, and because it has employed stringent cost-control measures throughout the planning process. Even if NSP's efforts in these areas are exemplary, the Commission is unconvinced that the Company's performance will deviate that sharply from industry norms. Furthermore, the Department presented convincing testimony that the demand for construction is likely to increase in the future, increasing inflationary pressures and narrowing the gap between steam plant escalation and general inflation. The Commission will therefore reject NSP's proposed escalation rates.

B. The Counties' Proposal

The Counties based their 5.5% escalation rate on the following factors: the Company's use of a 5.5% escalation rate for nuclear decommissioning costs; Data Resources, Inc.'s (DRI) projected 5% escalation rate for steam plant construction in the North Central region from 1986 through 1996; Edison Electric Institute's estimated escalation rate of 4.5% for 1988-1990; Engineering News Record's estimated escalation rate of 5.8% for 1987; DRI's projection of the Gross National Product Implicit Price Deflator, which ranges from 2.6% for 1986 through 5.6% for the year 2000; DRI's projection that steam plant construction escalation will average 5.5% per year from 1986-2000; the Electric Power Research Institute's projected long term inflation rate of 6% per year; and the Handy-Whitman Index's projection of 6.6% average escalation for plant construction in the North Central Region from 1973 to 1988.

The Commission does not believe the Counties' escalation rate of 5.5% is likely to prove accurate. The fact that the Company uses that rate for nuclear decommissioning has little probative value. Escalation rates for nuclear decommissioning have historically run higher than escalation rates for conventional plant construction. The decommissioning process is more technologically sophisticated, is subject to change in light of new technological and regulatory requirements, and is not carried out by NSP itself. Nuclear decommissioning escalation rates are not a reliable indication of plant construction escalation rates.

The Commission is not convinced that the independent sources relied upon by the Counties demonstrate that a 5.5% rate is the most reasonable choice either. The 6.6% average from the Handy- Whitman Index is based on the years 1973-1988, which include a period of extraordinarily high inflation. The usefulness of the 5.5% figure derived by averaging DRI's escalation projections for 1986 through the year 2000 is diminished by the fact that DRI's projections of plant construction escalation have historically exceeded actual escalation rates.[2] The 4.5% rate from a study by the Edison Electric Institute was limited to the years 1988-90, did not address regional variations, and included all types of generation facilities, including nuclear plants. The 5.8% figure from Engineering News Record was limited to a one-year period spanning parts of 1987 and 1988; the article itself suggested the increase was unusually high and unlikely to be repeated.

Finally, projections of general inflation rates introduced by the Counties, such as those of the Electric Power Research Institute and the Consumer Price Index, are helpful only as starting points, since they represent broad averages with no direct applicability to power plant construction costs.

C. Commission Action

Setting an escalation rate requires the Commission to exercise its own judgment. The rate set must be based upon the evidence presented by the parties and upon the Commission's institutional experience and expertise. As the Department noted, the rates in the record are part of a continuum. Even the rate advocated by each party resulted from that party's weighing and balancing conflicting information to settle upon an appropriate rate. It is therefore unsurprising that the Department's rate was derived in large part by making necessary adjustments to the rates proposed by the other two parties.

The Commission concurs in the Department's analysis and will adopt the escalation rate the Department proposed.

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[2]This has not been true of DRI's general inflation projections, discussed above.

IX. The Equity Adjustment

The Company proposed that avoided cost payments to the Counties be reduced by 33.04% to reflect the increase in equity costs which would result from assuming these long term obligations. The Company argued that the contracts with the Counties were sufficiently similar to debt to have the effect of debt on its capital structure, i.e., an increase in financial risk and in the cost of equity.

The Counties argued that the contracts would not increase the Company's financial risk, and would enable the Company to avoid business risks by purchasing power rather than constructing facilities to produce it.

The Department contended that the contracts were sufficiently debt-like to impose similar financial risks, but that the increase in financial risk was substantially offset by a reduction in business risks. The Department recommended an equity adjustment of 8.26%. The ALJ adopted the Department's position.

The Commission agrees with the Counties that there should be no equity adjustment to avoided costs. The contracts between the Counties and the Company do have some of the characteristics of debt. The Commission is unconvinced, however, that they are so like debt that they will have a similar effect on how the financial risk of the Company is perceived.

The Company presented expert testimony to the effect that the financial markets should view these contracts as debt, but no evidence that that is in fact how they view them. The only record evidence on that issue suggests the contrary. Standard & Poor's does not classify contracts with qualifying facilities as debt, and Value Line, a publication on which financial analysts rely, concluded that Virginia Power was rendered less risky by its increased reliance on qualifying facilities for new capacity. Also, there is no evidence in the record that any other state regulatory agency has applied an equity adjustment in setting rates for qualifying facilities.

Furthermore, the Commission agrees with the Counties and the Department that purchasing cogenerated power reduces the business risks faced by the Company. It reduces the risks of increased property taxes, construction cost overruns, under-performance of new generating facilities, increases in operating and maintenance expenses (especially fuel and labor costs), and disallowance of costs on prudence review. Any increased financial risk incurred under these contracts could easily be offset by these reduced business risks.

Finally, the Commission is required by law to set avoided costs in a manner which provides the maximum possible encouragement to cogeneration and small power production, consistent with protecting ratepayers and the public. Minn. Stat. § 216B.164, subd. 1 (1988); Minn. Rules, part 7835.0200. The Commission is also required to place the burden of proof as to all issues on the utility. Minn. Stat. § 216B.164, subd. 5 (1988); Minn. Rules, part 7835.4500. Clearly, applying an equity adjustment to avoided costs would act to discourage cogeneration and small power production. In the absence of a strong evidentiary showing that the interests of ratepayers, or the public interest, require such an adjustment, the Commission will not apply one.

X. On-Call Requirement

The Company proposed that the Counties' facilities be "on call," that is, ready to provide full committed capacity on four hours' notice, for up to 1,500 hours per year. The Company could exercise its call rights only in the following situations: a. the Company is interrupting or curtailing customers due to extraordinarily high peak load; b. the Company is interrupting or curtailing customers to reduce or avoid the use of oil-fired generation; c. the Company is experiencing a system emergency.

The Counties were originally ready to provide on call services 500 hours per year, but revised their position to 200 hours in light of testimony presented by NSP. The Department took the position that the Counties should be on call for 750 hours per year. The ALJ recommended an on call requirement of 500 hours per year. The Commission agrees with the Department that the Counties should be required to be on call for 750 hours per year.

The Commission recognizes that it is unlikely the Company will need 750 on call hours from the Counties in the foreseeable future. The Company testified that the three situations which would enable it to exercise its call rights usually occur only 100 to 200 hours per year. The Company also testified that it has called upon a qualifying facility in such situations only once. Finally, the Company testified that its next planned peaking plant, which is constructed to meet the same kind of needs as the on call requirement, is expected to operate only about 267 hours per year.

On the other hand, the purpose of the on call requirement is not limited to dealing with predictable and recurring needs for extra power, but also with unpredictable, extraordinary needs. In the absence of hardship to the Counties, which they have not alleged, it is reasonable to set the on call requirement higher than the number of hours normally needed.

Furthermore, the Commission believes that, as cogeneration and small power production become more common and constitute a more significant part of the Company's resource mix, the Company's need to rely on them will increase. The contracts at issue are 30-year contracts. Assuming the public policy of encouraging cogeneration and small power production continues, the Company's need to rely on cogenerated power will grow. The Company is anticipating this trend by negotiating higher on call requirements in its more recent contracts. The Commission considers this a prudent step to protect ratepayers and the public.

The Commission is not willing to grant the entire 1,500 hours requested by the Company. That figure is extreme in relation to what is currently required of most other qualifying facilities and in relation to what the Company's on call needs will probably be. The Commission believes that 750 hours represents a reasonable balance of the interests of both parties, and will approve an on-call requirement of 750 hours. The Commission will also approve inclusion of the Company-proposed damages clause, which was not identified as an issues by the parties, for the reasons given in the discussions of the damages clauses below.

XI. Reduction in Accredited Capability

The Company proposed that the contracts require the Counties to reimburse NSP for the difference between the price of power under the contracts and the price of replacement power, should the Counties be unable to provide agreed-upon power due to a reduction in accredited capability by MAPP. The Counties opposed this provision. The Department and the ALJ supported its inclusion.

The Commission believes it is reasonable to require the Counties to reimburse NSP for any losses it incurs by reason of their failure to maintain the accredited capability necessary to deliver the power promised. The Counties maintain that this provision should be viewed as a penalty, and that not receiving payments in such a situation should be penalty enough. The Commission disagrees. The provision is not a penalty clause. It is nothing but a common contract term requiring a party who breaks a contract to pay any additional costs that imposes on the other party. If the Counties fail to deliver the power promised, and NSP incurs costs higher than the contract costs to replace it, it is merely equitable that the Counties, not NSP and its ratepayers, pay those additional costs.

The Counties also argue that NSP does not face similar consequences if its facilities are derated. Again, the Commission disagrees. NSP is subject to continuing Commission oversight. In the event its facilities fail to perform as expected, the Company is subject to action imposing the financial consequences of non-performance on the shareholders instead of the ratepayers. In fact, that is precisely what occurred when NSP recently incurred replacement power costs exceeding its normal costs as a result of a coal dust explosion at Sherco.

The Commission will approve the inclusion of the replacement cost damages provision in the contracts at issue.

XII. Non-delivery of Committed Capacity

NSP proposed that the Counties be required to reimburse the Company for the difference between the cost of replacement power and the cost of power under the contracts if they failed to deliver promised power for reasons other than those excused under the force majeure provision of the contracts. The Counties characterized this provision as a penalty, claimed it was inequitable because NSP was not required to pay the Counties if replacement power was less expensive than contract power, and argued that reimbursement should be required only if the Counties sold power to a party other than NSP.

The Commission agrees with the Company, for the reasons set forth in the discussion of reduction of accredited capability. The provision at issue is not a penalty; it merely places the financial risks of non-delivery on the party who agreed to deliver. Furthermore, the Counties are adequately protected from inadvertent non-performance by the force majeure provision of the contracts. They offered no examples of situations in which circumstances beyond their control would result in damages under the clause. Finally, the provision is not rendered inequitable by its failure to require NSP to pay the counties if the cost of replacement power is lower than the cost of contract power. The purpose of the provision is to make NSP and its ratepayers whole. The Company would not derive a windfall from any damages assessed under the clause, and equity does not require that the clause provide a windfall to the Counties in the event of non-performance.

The Commission will approve the inclusion of the replacement cost damages provision for non-delivery not excused by force majeure.

XIII. Continuing Compliance with MAPP Agreement

The Company proposed that the Counties be required to ensure that their facilities conform with all future amendments to the Mid-Continent Area Power Pool (MAPP) agreement. The Counties proposed that they be required to conform only to amendments which did not result in a material change in either party's rights, obligations, or economic benefits under the contracts. In the event that incorporating MAPP changes would cause material change, the parties would re-negotiate affected contract terms, subject to arbitration. The Commission agrees with the Counties.
The Commission understands NSP's concern that it receive reliable power, and agrees that conformity with MAPP requirements is a reasonable approach to ensuring reliability. On the other hand, qualifying facilities are not signatories to the MAPP Agreement, do not have a voice in setting MAPP policies, and may have difficulty achieving prompt or total compliance with changes in the Agreement. It would be inequitable to require the Counties to incorporate MAPP-mandated changes materially affecting their contractual obligations without allowing renegotiation of the contracts. The Commission will require inclusion of the Counties' proposed contract terms regarding changes in the MAPP Agreement.

XIV. Avoided Societal Costs

The Counties proposed in their initial brief that NSP's avoided costs be increased by 20% to reflect the greater social value of solid waste recovery as compared with fossil fuel consumption. The

Company opposed the adjustment. The Department and the ALJ agreed with the Company.

The Commission does not believe this is an appropriate case to make an adjustment for non-internalized costs. There is no evidence in the record even purporting to quantify and compare the social costs of burning garbage and burning coal. It is not clear that one is superior to the other. As the Department noted, burning garbage causes toxic emissions. Neither the record nor common knowledge demonstrates that those emissions are less hazardous than emissions from coal-fired power plants. It is also possible that garbage burning will slow the development of recycling programs, which many believe to be the most ecologically sound approach to solid waste. Finally, the argument that avoided costs should reflect reduced landfill costs is unpersuasive, since garbage collection fees are a more appropriate and direct means of reflecting that reduction.

The Commission will not impose a 20% adjustment to avoided cost to reflect the social benefits of these qualifying facilities.

XV. Anti-competitive and Discriminatory Behavior

The Counties alleged that NSP engaged in anti-competitive and discriminatory behavior in its negotiations with the Counties and that the Company should therefore face a heightened evidentiary standard. The Company, the Department, and the ALJ disagreed. The Commission disagrees as well.

The Counties based their claims of discrimination and bad faith on the following incidents, which occurred during negotiations: the change in proxy plant from Sherco 3 to the reference plant, the addition of capacity from Minnkota Power Cooperative, the execution of contracts with other qualifying facilities and utilities at higher prices, the refusal to provide detailed letters of intent to the Counties, the insistence on a higher call requirement than has consistently been required in the past, the insistence on damages for failure to deliver committed capacity or failure to maintain full accredited capability, the insistence on conformity with future MAPP requirements, and the revision from 1997 to 1998 of the date when the Company will require new base load capacity.

The Counties allege that NSP had a strong motive to engage in discriminatory behavior, because it had decided to enter the garbage burning market itself. They argued that the Company's negotiating strategy was to delay agreement long enough, or to make the terms of the agreement onerous enough, to force the Counties to abandon their construction plans and sell their municipal waste to NSP instead.

The Commission finds no support in the record for this contention. Some of the Company positions alleged to be discriminatory have been found reasonable by the Commission, i.e., the damages provisions for failure to deliver committed capacity or to maintain full accredited capability, and the change in proxy plant from Sherco 3 to the reference plant. Others were accepted by the Commission in revised form, e.g., the increase in the on-call requirement and the requirement of conformity with changes in the MAPP Agreement. None of the other instances of alleged discrimination was so outside the range of normal behavior as to suggest discrimination or bad faith.

First of all, it is true that NSP used Sherco 3 as the proxy plant in a few qualifying facility contracts executed after its costs were no longer avoidable. In all those cases, however, contract negotiations were at such an advanced stage that it was not logical to reopen them to recompute avoided costs. Furthermore, the Counties themselves concede that avoided costs are not materially different whether based on Sherco 3 or the reference plant. This severely weakens any claim of discrimination based on the shift in the proxy plant.

Similarly, the Commission is unconvinced there was discriminatory intent underlying the Minnkota Power Cooperative purchase. The Company signed a letter of intent regarding the purchase in 1985, substantially before the impasse in negotiations with the Counties. Furthermore, the Company has a duty to ratepayers to obtain power on the most economical terms available, and it would have been imprudent to forgo the Minnkota purchase merely because it might affect the avoided costs payable to the Counties or any other cogenerators with whom it might be negotiating.

NSP's revision of its base load capacity forecasts during the course of its negotiations with the Counties does not suggest bad faith either. There has been no showing that these revisions were aberrant in number or scope for a utility NSP's size or that they were not attributable to genuine changes in the Company's capacity situation.

The fact that NSP has negotiated contracts with other qualifying facilities at higher rates does not establish discrimination. The Department pointed out correctly that avoided costs are not static and that NSP's avoided costs have legitimately fallen, due to changes in capacity, market prices, and cost-saving technologies.

Finally, the Counties have presented no evidence that they asked NSP to provide them with letters of intent or that the letters offered by the Company were inadequate for the Counties' purposes.

XVI. Attorneys' Fees

The cogeneration and small power production statute provides for the payment of costs, disbursements, and attorneys' fees under the following conditions:

> . . . . The commission in its order resolving each such dispute shall require payments to the prevailing party of the prevailing party's costs, disbursements, and reasonable attorneys' fees, except that the qualifying facility will be required to pay the costs, disbursements, and attorneys' fees of the utility only if the commission finds that the claims of the qualifying facility in the dispute have been made in bad faith, or are a sham, or frivolous.
>
> Minn. Stat. § 216B.164, subd. 5 (1988).

The rules contain a similar provision:

> In the order resolving the dispute, the commission shall require the prevailing party's reasonable costs, disbursements, and attorney's fees to be paid by the party against whom the issue or issues were adversely decided, except that a qualifying facility will be required to pay the costs, disbursements, and attorney's fees of the utility only if the commission finds that the claims of the qualifying facility have been made in bad faith or are a sham or frivolous.
>
> Minn. Rules, part 7835.4550.

The Commission will require the parties to submit comments on implementation of this provision for Commission consideration.

ORDER

1. The Commission resolves each of the issues submitted to it for resolution in the following manner:

    a. Avoided costs shall be computed on the assumption that the Company will require additional base load capacity in 1997.

    b. Avoided costs shall be computed using the reference plant as the proxy base load plant.

    c. Avoided costs shall be computed using an escalation rate of 3% through 1996 and 4% thereafter.

    d. Avoided costs shall be computed without an equity adjustment.

    e. The contracts at issue shall require the Counties to provide full committed capacity in the situations specified for up to 750 hours per year.

    f. The contracts at issue shall require the Counties to reimburse the Company for the difference between the cost of replacement power and the cost of power under the contracts if the Counties fail to maintain the MAPP accredited capability agreed upon.

g. The contracts at issue shall require the Counties to reimburse the Company for the difference between the cost of replacement power and the cost of power under the contracts if the Counties fail to deliver committed capacity for reasons other than those excused under the force majeure provisions of the contracts.

h. The contracts at issue shall require the Counties and the Company to renegotiate any material terms which would be changed by the Counties' compliance with any future amendments to the MAPP Agreement, and they shall be required to enter into arbitration in the event of an impasse.

i. Avoided costs shall be computed without an adjustment for avoided societal costs.

2. Within 20 days of the date of this Order, all parties shall submit initial comments on implementation in this case of the costs, disbursements, and attorneys' fees provisions of the statute and the rules. Reply comments shall be due within 10 days thereafter.

3. The parties shall file copies of the contracts finally executed within 10 days of signing.

4. This Order shall become effective immediately.

BY ORDER OF THE COMMISSION

Mary Ellen Hennen
Executive Secretary

(S E A L)